The Influence of Interfacial Tension on Water-Oil Two-Phase Relative Permeability

Pingping Shen[1], Bin Zhu[1], Xian-Bin Li[1], and Yu-Shu Wu[2]*

[1] Research Institute of Petroleum Exploration and Development, Beijing, China

[2] Earth Sciences Division, Lawrence Berkley National Laboratory, Berkeley, USA

Abstract

Water-oil relative permeability, related to all two-phase flow properties, characterizes two-phase flow and displacement processes in porous media. Therefore, relative permeability is inherently complicated and its functional form is difficult to determine in a particular reservoir study. For example, adding various chemical agents into the displacing aqueous phase during alkaline-surfactant-polymer combination chemical flooding in oil production significantly changes interfacial tension (σ) on water-oil interfaces, and also increases the degree of difficulty in measuring such changes in the laboratory or field. To overcome the limitations of the existing laboratory measurements of relative permeability (which are applicable only for high ranges of interfacial tension (e.g., $\sigma > 10^{-2}$ mN/m), we present a comprehensive experimental study of two-phase relative-permeability functions in much lower, realistic interfacial tension water-oil systems. In particular, we have (1) develop an improved steady-state method of measuring water-oil relative permeability curves; (2) proven that a critical interfacial tension value (σ_c) exists such that interfacial tension has little impact on relative permeability for $\sigma > \sigma_c$, while if $\sigma < \sigma_c$, relative permeabilities to both water and oil phases will increase with decreasing interfacial tension; (3) shown that a logarithmic relation exists between water-oil two-phase relative permeability and interfacial tensions. The experimental results and proposed conceptual models will be useful for feasibility studies, optimal designs, and numerical simulations of different chemical flooding operations in oil reservoirs.

Key Words: interfacial tension; relative permeability; steady-state test, two-phase displacement, chemical flooding

---

* Corresponding author. Tel.: +1-510-486-7291; fax: +1-510-486-5686. E-mail: YSWu@lbl.gov.

1. Introduction

With increasing demand for oil, and at the same time large decreases worldwide in newly discovered oil reserves in the past few decades, more efficient development of oil and gas from existing reservoirs, using enhanced oil recovery (EOR) methods, has received greater attention. Since the 1970s, as a result of industry-wide efforts to improve oil recovery rates, many EOR techniques have been developed and applied to various oil fields. In general, EOR methods, such as chemical flooding, miscible flooding, and thermal recovery techniques, rely on altering the mobility and/or the interfacial tension (IFT) between the displacing and displaced fluids to improve sweep or displacement efficiency. Among the various EOR approaches developed, chemical flooding, with various chemical surfactants and agents added into the injected fluids, is among the most widely used. This technology has been found to be suitable and cost-effective in improving oil recovery rates from reservoirs subjected to a long history of many previous water-flooding operations.

Because of the additional interactions between fluid phases, chemical components, and solid porous rock, flow behavior within chemical flooding is in general more difficult to characterize than that within oil displacement in conventional water flooding. Even with the significant progress made in understanding two-phase flow mechanisms of chemical flooding over the past few decades, it remains a challenge to quantitatively assess such flow behavior. It is even more difficult to predict whether this technique can be successfully applied to a given oil field. One of the primary difficulties is the lack of physical insight or constitutive correlations for describing mutual effects or interplay between phases during chemical flooding processes, a deficiency that hinders quantitative analysis.

Past investigations have shown that quantitative characterization of multiphase flow phenomena by chemical flooding is crucial for understanding chemical flooding processes and assessing their applications. Among the various evaluation techniques applied, numerical modeling has been among the most important and convenient tools to use in analyzing physical processes, especially on the temporal and spatial scales relevant to a

particular chemical flooding operation in reservoirs. Since the late 1950s, significant progress has been made in developing and applying numerical simulation techniques in petroleum engineering (e.g., Aziz and Settari, 1979; Coats, 1987; Peaceman, 1997) and groundwater modeling (Huyakorn and Pinder, 1983; Istok, 1989). Continual research effort, driven by the need to develop underground natural resources and resolve subsurface contamination problems, has provided many numerical modeling approaches and models for field applications.

Numerical modeling approaches currently used for simulating multiphase flow and transport processes in porous media have become very sophisticated, and are capable of routinely solving problems ranging from simple groundwater flow to coupled multiple-physical-process reservoir simulations. Practical applications of reservoir simulation techniques (e.g., for assessing chemical flooding) are often limited by the lack of site-specific fluid and rock parameters. Simulation techniques are also limited in applications because of insufficient studies describing interrelations or mutual influences of multiphase flow and transport processes, such as relative permeability, in chemical flooding. These limitations motivate us to perform this experimental study of relative permeability behavior as influenced by interfacial tensions.

The primary goal in an EOR operation is to produce more remaining oil from existing reservoirs than can be achieved using conventional water flooding techniques. Remaining oil left in reservoirs after long-time water-flooding operations is normally discontinuously distributed in pores. From the viewpoint of fluid flow mechanics, there are two main forces acting on residual oil drops: viscous and capillary forces. Microscopic displacement efficiency with an EOR method depends on the relative influence or ratio of these two forces. Melrose and Brandner (1974) define capillary number as the ratio of viscous forces and capillarity:

$$N_c = \frac{\mu_w V_w}{\phi \sigma_{wo}} \tag{1}$$

where N_c is the capillary number; μ_w is the viscosity of aqueous or displacing phase; V_w is the flow rate of the displacing phase; ϕ is the effective porosity of formation; and σ_{wo} is the

water-oil interfacial tension.

Another useful parameter for quantitative analysis of oil recovery operations is the microscopic displacement efficiency (E_m), defined as:

$$E_m = \frac{1 - S_{or} - S_{wc}}{1 - S_{wc}} \qquad (2)$$

where S_{or} is residual oil saturation and S_{wc} is irreducible or connate water saturation.

Using experimental results, Fulcheret et al. (1985) show that change in the capillary number has a significant effect on the residual oil saturation of the system. The interfacial tension between crude oil and *in situ* brine ranges normally from 20 to 30 mN/m under normal reservoir conditions, and the capillary number is at about 10^{-6} for general water flooding reservoirs. The residual oil saturation is approximately at 40%, and microscopic displacement efficiency of about 40% can be reached. As the capillary number rises to 10^{-2}, however, the residual oil saturation could be lowered to near zero and displacement efficiency be theoretically close to 100%, as shown in Figure 1.

Adding surfactants to displacing fluids during chemical flooding operations lowers the interfacial tension between injected liquid and oil phases. Without changing the viscous forces (e.g., maintaining flow rates and viscosity or the viscosity-ratio relative constant), it is possible to reduce the interfacial tension as low as 10^{-3} mN/m (i.e., four orders of magnitude decrease) by adding surfactants or adjusting their concentrations in the displacing fluids. This increases the capillary number to above a value of 10^{-2}, to achieve an optimal oil displacement result (See Figure 2). At the same time, water-phase relative permeability at residual oil saturation after waterflooding will continuously increase as the capillary number increases (See Figure 3).

By altering interfacial tension between water-oil (water-gas or oil-gas) phases, surfactants cause significant changes in two-phase flow behavior. Therefore, many researchers have studied relative permeability with flow systems involving interfacial tension. Among the earlier efforts, Talash (1976) presented a modified Naar-Wygel equation exponential function to describe the relationship between relative permeability and normalized saturation under low interfacial tension conditions. By comparing with laboratory measurements, the modified model was found to fit well for relative permeability curves near both ends of saturation ranges, but not well for the middle portion of the curves.

Lawson and Hirasaki (1983) published a more detailed study of flow behavior under low interfacial tensions. They found that two-phase flow and displacement were very different for a water-oil system with or without adding a surfactant, and showed that concentration, adsorption onto the rock, and partitioning of surfactants into the oleic phase all affected relative permeability curves and their variations.

Asar and Handy (1988) measured relative permeability curves for two-phase flow of "oil" (methane, ethane, or kerosene) and gas (nitrogen) under different interfacial tensions, ranging from 0.033 to 30 mN/m. Based on shapes and extrapolations of measured relative permeability curves under different interfacial tensions, they predicted that the relative permeability curves for water and oil phases would become two diagonally straight lines (i.e., relative permeability equal to saturation) at zero interfacial tension. This argument or prediction has received wide acceptance in the petroleum industry and even has been extended for flow in a water-oil system.

In addition, a number of studies indicate that there may exist a critical interfacial-tension value below or above which impact of interfacial tension on relative permeability is very different. This hypothesis has been confirmed by the results from investigating a low interfacial tension, water-oil system (Harbert, 1983) and a low interfacial tension, oil-gas system (Bardon and Longeron, 1980). Both these studies found that relative permeability curves changed significantly under the condition of interfacial tension lower than 0.04 mN/m, and for this low range of interfacial tension, their model appeared to fail. According to relative permeability curves measured from consolidated sandstone cores, Torabzadeh and Handy (1984) further categorized flow systems into a relatively high interfacial tension system, with $\sigma > 20$ mN/m, and a relatively low interfacial tension system, with $\sigma < 0.19$ mN/m. They considered that these were the two distinguishing zones of interfacial tensions for which relative permeability had different characteristics. Kumar et al. (1985) carried out more experimental studies, classifying interfacial tension into three ranges for the relationships of residual oil or water saturation versus interfacial tension. For high interfacial tension with $\sigma > 1.0$ mN/m, residual saturations are independent of interfacial tension and are functions of temperature only. However, under low interfacial tensions (0.15 mN/m $< \sigma < 1.0$ mN/m) and an ultra-low tension system with $\sigma < 0.150$ mN/m, two-phase residual saturations behave differently as functions of both temperature and interfacial tension.

To overcome the well-known difficulties in measuring relative permeability curves

under low interfacial tensions, several attempts at investigating two-phase flow behavior were made, involving either increasing viscous forces in displacing fluids or increasing the capillary number (Fulcher et al., 1985; Peters and Khataniar, 1985; Chisholm et al., 1990). However, a large increase in viscosity of the displacing, aqueous phase may lead to too much decrease in displacing rates or mobility. On the other hand, very high flow rates will cause small rock solids or particles to migrate. As a consequence, those approaches cannot in general achieve the capillary-number ranges appropriate for normal combinational chemical flooding.

In addition to the effects of saturation, interfacial tension, and temperature, relative permeability is also affected by pore structure or porous medium characteristics. To describe these effects, many researchers have devoted considerable effort towards deriving closed-form equations to correlate these factors with relative permeability functions. Among the early investigations, Fatt and Dykstra (1951) introduced the tortuosity concept and presented a relative permeability model that correlates relative permeability and pore structures as well as capillary pressures. In a subsequent effort, Brooks and Corey (1964 and 1966) developed an equation that correlates capillary pressure with pore distribution and saturation, a closed-form equation that has been widely used ever since.

As the literature indicates, many studies have been carried out regarding two-phase flow and displacement processes under different interfacial tensions (Bardon and Longeron, 1980; Chisholm et al., 1990; Asar and Handy, 1988; Haniff and Ali, 1990;, Ronde, 1992; Conway et al., 1995; McDougall et al., 1997; Tang and Firoozabadi, 2002; Mulyadi et al., 2002). The majority of these studies, however, were performed for either *oil-gas* or *water-gas* two-phase systems. In addition, the ranges of interfacial tensions covered in these investigations were limited mostly to 10^{-1} to 40 mN/m (or higher than 10^{-2} mN/m). Few studies have been conducted for the effect of lowering interfacial tensions as a result of adding surfactants into water-oil systems. This is mainly because it is difficult to conduct such experiments and measurements (i.e., involving low interfacial tensions) under laboratory conditions, because of the complexity in chemical properties and their variations, such as chemical reactions and adsorption effect.

In recent years, extensive studies from laboratory to field applications have been carried out in China for large-scale enhanced oil recovery projects. In the 1990s, field pilot tests were carried out, using the alkali-surfactant-polymer combinational flooding approach, at several oilfields in China. As part of the field-application efforts, laboratory studies of low-interfacial-tension relative permeability for water-oil systems were also

conducted. Using a dynamic method, Wang et al. (2002) and Lu et al. (2003) measured end values of relative permeability and remaining residual oil saturation for low interfacial tension water-oil systems. They showed the effects of water-oil interfacial tension on the end values of relative permeability under transient displacement. To avoid the large, undesirable effect of nonequilibrium adsorption of surfactants on relative permeability, Ye et al. (1995) attempted to use a steady-state method for measuring end relative-permeability values, and made some useful findings regarding the effect of interfacial tensions on residual oil saturation. However, no complete relative permeability curves were obtained because of the difficulties encountered in their measurements.

To fill the large gap between research and application regarding water-oil relative permeability under different interfacial tensions, this paper presents a comprehensive experimental study of the effects of low interfacial tension on two-phase relative permeability in water-oil systems. In particular, we present a new, improved steady-state method for measuring water-oil relative permeability curves. The experimental results indicate that there exist two critical interfacial tension values that separate ranges of effects of interfacial tensions on relative permeability and residual oil saturations. In addition, based on two-phase experimental data from sandstone cores, a two-phase relative permeability model is proposed to correlate water-oil two-phase relative permeability with interfacial tension and saturations. The experimental results and proposed relative permeability model will be useful for numerical simulation and other quantitative studies of chemical flooding operation in oil reservoirs.

2.   Experimental Procedure and Method

To eliminate the effects complex chemical processes occurring at water-oil interfaces on measurements, we adopted a steady-state method for measuring water-oil relative permeability within a low-interfacial-tension system. The steady-state approach ensures that equilibrium is reached for partitioning of chemical agents between water-oil phases and rock solids of adsorption.

2.1   Water-Oil System

Oil Phase: To make the experiment as well as measurements repeatable, the oil used in this study is called "model oil," which has been systematically treated to remove its active components (through filtering and depolarizing processes). The viscosity of the treated oil is at about 1 cp.

Aqueous Phase: Brine, consisting of 5,000 mg/L of NaCl (sodium chloride), is used in the water-oil system as the aqueous phase. It also serves as a base liquid for constructing various low interfacial tension fluid systems.

Fluid mixtures with low interfacial tensions used for oil displacement in EOR operations are usually composed of various chemical additives. When interfacial tension is lower than 10^{-1} mN/m for most systems, different levels of emulsification will occur. This makes it difficult to measure relative permeability curves. To resolve this problem, many receipts of combining chemical mixtures were tested. Finalists were screened and selected by the following criteria:

(1) They enable ultra low interfacial tension ($\sim 10^{-3}$ mN/m) with both the model oil and crude oil from reservoirs.

(2) The degree of emulsification has little impact on measurements of water and oil saturations, in repeated use and after flushing cores many times.

Chemical components chosen for this study are: 2SY+NaCl (0.5%wt)+NaOH (sodium hydroxide). Here, 2SY stands for alkyl benzene sulfonate, which in China is a widely used surfactant for chemical flooding mixtures in the laboratory.

2.   Porous Cores

Sandstone cores for the experiment are made from outcrops located in Sichuan, China. These outcrop samples have intermediate permeability ranges, which make them suitable for study of water-oil flow and displacement processes under different interfacial tensions. Table 1 lists basic properties of the 1-inch diameter cores, which were used in this study. The main reason for using these outcrop cores is that the sandstone contains little (less than 1%) clayey or swollen materials, such as kaoline and chlorite. In addition, rock solids of the cores show only a very weak adsorbing effect with the chemicals selected, which helps

to minimize or avoid interference between chemicals and clayey minerals in measurement and analysis of flow behavior.

All the cores are thoroughly cleaned with liquid detergents to be strongly water wet. After cleaning, they are dried completely in oven at $105^{\circ}C$ until no change in weight was observed.

3.3 Measurement and Instrument

A schematic or flow chart of the experimental setup, instrument, and procedure of this study is shown in Figure 4. During experimental measurement of relative permeability curves using the steady-state method, two pumps (Quizix) were used to regulate injection, displacement, and recycling of water and oil. Confining pressures within the cylindrical space were controlled by a separate, manual hydraulic pump. In addition, several electromanometers with different measurement-scale ranges were employed to measure pressures at the inlet and outlet ends. Water and oil saturations were estimated by a mass-balance calculation using the scaled glass water-oil separator of Figure 4. A tensometer (TX500C) was used for measuring interfacial tension.

3.4 Measurement of Relative Permeability

To account for the time needed for adsorption to reach equilibrium between chemicals and cores (i.e., to eliminate nonequilibrium sorption effects), a steady-state method was in this study for measurement of relative permeability curves. Only the cores with strong water wettability were selected, as determined by spontaneous imbibition indexes.

First, all the selected cores were fully saturated with brine having a sodium chloride concentration of 4,500 mg/L. Then, water-phase permeability at zero oil saturation was measured from these 100% brine saturated cores.

To assure reaching adsorptive equilibrium between chemicals and cores at different saturations, we determined the first value of water saturation (i.e., a minimum value of water saturation to start with in the experiment) after more than two days of continuous injecting and recycling of the fluids through the core. By varying ratios of water and oil-injection rates at pumps, oil saturation was adjusted to increase gradually. Once a new

steady state was reached, all parameters were measured and recorded, and relative permeability values for water and oil phases were then calculated by a steady-state Darcy's law.

There are a total of five fluid systems (Table 2) used in this study, covering five different ranges of interfacial tensions.

4. Results and Discussion

4.1. Surfactant-Flooding Characteristics and Interfacial Tensions

The experimental results indicate that there exists a certain correlation between residual oil saturation after water flooding operations, and water-oil interfacial tension under different surfactant concentrations within fluid systems. With the selected water-wetting cores under laboratory temperature conditions, for example, there are two critical values (σ_{C1} and σ_{C2}) observed in interfacial tension values (Figure 5). When $\sigma > \sigma_{C1}$ (= 3 mN/m, the first or high critical point), residual oil saturation of the water flooding remains at about 0.40. This residual saturation value of 0.40 appears to be unvarying with changes in interfacial tension within this range. On the other end of the curve, as shown in Figure 5, residual oil saturation is also kept as a low-level constant for $\sigma < \sigma_{C2}$ (= 0.01 mN/m). For the intermediate values of interfacial tension (i.e., $\sigma_{C1} < \sigma < \sigma_{C2}$), however, Figure 5 shows that residual oil saturation rapidly decreases with decreasing interfacial tension. In other words displacement efficiency increases significantly with decreasing interfacial tension.

The relationship between residual oil saturation and interfacial tension, under the different interfacial tensions of this study's core-fluid system, can be further quantified using a regression analysis. Fitting and statistical analysis of experimental data yields the following expression:

$$S_{or} = \frac{\sigma_{wo}^{1.5}}{A\sigma_{wo}^{1.5} + B} \quad (r^2 = 0.9995, F_{stat} = 5517) \tag{3}$$

where A and B are constants related to cores and experimental conditions (A = 2.432, B = 0.1154, fitted from our experimental data), and r and f are the correlation coefficient and F-test of statistics, respectively. As shown in Figure 5, the results of using Equation (3) (labeled as "calculational") match the experimental data points well.

Relative permeability characteristics are observed to be very different under the different interfacial tensions of the studied water-oil systems. Figure 6 shows the experimental results of water and oil relative permeabilities and their variations under different values of interfacial tensions at a constant saturation of $S_w = 50\%$. Note that when $\sigma > \sigma_{C1}$ (= 3 mN/m), water relative permeability is at about 0.08, and that oil relative permeability is at 0.2 at the water saturation value of 50%. The two relative permeability values are almost constants over this range of interfacial tensions. In contrast, relative permeabilities to both phases increase continuously as interfacial tension decreases for $\sigma < \sigma_{C1}$. In general, the rate of increase in the water relative permeability appears larger than that of oil relative permeability within the low range of interfacial tensions.

After fitting many sets of experimental data, we obtained the following equation for describing water and oil relative permeability curves versus interfacial tensions at $S_w = 50\%$:

$$k_{rw}(50\%) = \exp[A_w + B_w \ln(\sigma_{ow})] \quad (r^2 = 0.7443, F_{stat} = 11.65) \tag{4}$$

and

$$k_{ro}(50\%) = \exp[A_o + B_o \ln(\sigma_{ow})] \quad (r^2 = 0.7405, F_{stat} = 11.42) \tag{5}$$

where $k_{rw}(50\%)$ is relative permeability for water phase at water saturation of 50%; $k_{ro}(50\%)$ is relative permeability for oil phase at water saturation of 50%; A_w, B_w, A_o, and B_o are constants related to cores and experimental conditions.

Note that the results in Figures 5 and 6 are consistent with the trends similar to those in the literature (e.g., Fulcher et al., 1985).

4.2 Normalized Relative Permeability

To analyze the two-phase flow and displacement processes of various water-oil

systems with different interfacial tensions (e.g., for numerical simulation studies), we need complete relative permeability curves, not just their end values. Figure 7 presents such relative permeability curves, determined from our experimental measurements for two-phase flow, subject to different interfacial tensions. Because the aqueous phase contains different amount of surfactants, significant differences exist in interfacial tensions among the two-phase fluid systems. As a result, relative permeability curves obtained for different interfacial tensions have not only very different end values, but also very different in shape. This makes it difficult to compare and analyze experimental results for different interfacial tensions.

Experimental data can be analyzed using the following normalized parameters and functions (Ahmed, 2001). Normalized water saturation is defined as:

$$S_w^* = \frac{S_w - S_{wc}}{1 - S_{wc} - S_{or}} \qquad (0 \leq S_w^* \leq 1) \qquad (6)$$

Normalized relative permeability to water phase is defined as:

$$k_{rw}^* = \frac{k_{rw}}{\left(k_{rw}\right)_{S_{or}}} \qquad (0 \leq k_{rw}^* \leq 1) \qquad (7)$$

and normalized relative permeability to oil phase is:

$$k_{ro}^* = \frac{k_{ro}}{\left(k_{ro}\right)_{S_{wc}}} \qquad (0 \leq k_{ro}^* \leq 1) \qquad (8)$$

where S_w^* is the normalized wetting, aqueous phase saturation; k_{rw}^* is the normalized aqueous-phase relative permeability; k_{ro}^* is the normalized oil-phase relative permeability; $\left(k_{rw}^*\right)_{S_{or}}$ is the aqueous-phase relative permeability at residual oil-water saturation; $\left(k_{ro}^*\right)_{S_{wc}}$ is the oil-phase relative permeability at connate water saturation; and S_{wc} is the connate water saturation.

Figure 8 displays the normalized relative permeability curves for two-phase flow, using the same results in Figure 7 for different interfacial tensions. It appears from Figure 8

that after normalization, only small differences appear in both oil and water relative permeability curves for $\sigma > \sigma_{C1}$. Significant changes in normalized relative permeability curves occur as interfacial tensions change when $\sigma < \sigma_{C1}$.

4.3 Relative Permeability Model for Low Interfacial Tension

Many studies (e.g., Fulcher et al., 1985; Kumar et al., 1985; Brooks and Purcell, 1952) have shown that water-oil relative permeability for two-phase flow systems is a function of saturation, rock-pore characteristics, temperature, interfacial tension, and capillary number. Even though a number of different forms of relative permeability functions have been proposed, simple exponential equations have been among the most widely used relationships in reservoir simulation and groundwater modeling (Honarpour et al., 1986). In our experiment, water and oil viscosities and displacement rate remain constant. Therefore, relative permeability from our experiments is considered as a function of saturation, interfacial tension, and properties of core pores only. Based on the experimental measurements, we propose the following two-phase-flow relative permeability models:

$$k_{rw} = m_w \left(S_w^* \right)^{n_w} \tag{9}$$

and

$$k_{ro} = m_o \left(1 - S_w^* \right)^{n_o} \tag{10}$$

where m_w and m_o are coefficients of water and oil relative-permeability functions, respectively; and n_w and n_o are exponential constants or indexes of water and oil relative-permeability functions, respectively.

Note that m_w is the water relative permeability at $S_w^* = 1$ and m_o is the oil relative permeability at $S_w^* = 0$, respectively. By definition, we have $m_w = \left(k_{rw}^* \right)_{S_{or}}$ and $m_o = \left(k_{ro}^* \right)_{S_{wc}}$. Therefore, the normalized formula can be derived from Equations (9) and (10) as

$$k_{rw}^* = \left(S_w^* \right)^{n_w} \tag{11}$$

and

$$k_{ro}^* = \left(1 - S_w^*\right)^{n_o} \tag{12}$$

The two exponential indexes, n_w and n_o, can be related with interfacial tension and pore size distribution parameters, λ_w and λ_o, as

$$n_o = n_o(\sigma_{wo}, \lambda_o) \tag{13}$$

and

$$n_w = n_w(\sigma_{wo}, \lambda_w) \tag{14}$$

Using a statistical analysis for the experimental data obtained with different interfacial tensions, n_w and n_o have been estimated as listed in Table 3.

Let us further discuss the role played by the interfacial tension in impacting relative permeability curves. A recent study with an artificial neural network model (Silpngarmlers et al., 2002) indicates that for a given fluid system, relative permeability functions are closely related to the following groups of fluid and rock parameters:

$$\sigma_{wo}S_{wc}, \ \sigma_{wo}S_{or}, \ \ln(\sigma_{wo}), \ \text{and} \ \ln(\mu_w/\mu_o/\sigma_{wo}) \tag{15}$$

where μ_o is the viscosity of oil phase. Although neural network modeling cannot provide a closed-form equation in general, it could help reveal the interrelationship between these parameters within two-phase flow permeability functions for a given fluid-rock system.

Based on our experimental data and line-fitting results in Table 3, the particular relations between exponential constants and interfacial tensions can be written as:

$$n_o(\sigma_{wo}, \lambda_o) = 0.1960 \times \log(\sigma_{wo}) + 2.006 \quad (r = 0.9911) \tag{16}$$

and

$$n_w(\sigma_{wo}, \lambda_w) = 0.9371 \times \log(\sigma_{wo}) + 3.807 \quad (r = 0.9975) \tag{17}$$

Accordingly, the two-phase relative permeability model, Equations (11) and (12), has the form:

$$k_{rw}^* = \left(S_w^*\right)^{\left[0.9371 \cdot \log(\sigma_{wo}) + \lambda_w\right]} \tag{18}$$

and

$$k_{ro}^* = \left(1 - S_w^*\right)^{\left[0.1960 \cdot \log(\sigma_{wo}) + \lambda_o\right]} \tag{19}$$

where λ_w and λ_o are constants for water and oil relative permeability, respectively, for the same rock type. The two parameters, λ_w and λ_o, should be determined from pore properties of core samples, dependent on pore size distribution, tortuosity, and phase distribution within pores (wettibility). With the sandstone outcrop cores associated with the fluids of this study, curve fitting of the experimental data leads to $\lambda_w = 3.807$ and $\lambda_o = 2.006$.

Figure 9 displays the relationships between the two exponential indexes and interfacial tension. As shown in Figure 9, interfacial tension has a small effect on n_w and n_o, when $\sigma > \sigma_{C1}$ (3mN/m); whereas for $\sigma < \sigma_{C1}$ (3mN/m), both water and oil exponential indices decrease with decrease in interfacial tensions. However, the index, n_w, for the water phase decreases at a much larger rate. This is consistent with the observation of different relative permeability behavior for different ranges of interfacial tension, separated by their critical values.

It appears that as interfacial tensions decrease, two exponential indices also decrease. This will make both water and oil relative permeability curves tend to be straighter. As shown in Table 3 and Figure 9, the exponential indices are still not close to one, even with very low vale of interfacial tension ($\sigma = 0.01$ mN/m). Therefore, the corresponding relative permeability curves are still not yet straight lines.

5. Summary and Concluding Remarks

This paper presents a comprehensive experimental study of two-phase relative permeability functions in a low-interfacial-tension water-oil system. By analyzing the experimental data, the following results and conclusions can be drawn:

1. A new steady-state method for measuring relative permeability data has been developed. This new steady-state method (with the designed experimental system) can be used to measure entire relative permeability curves, including low interfacial tensions, accurately and efficiently.

2. There exist two critical values or points (σ_{c1} and σ_{c2}) in interfacial tensions for the systems of fluids and porous media used in this study.

3. Residual oil saturation tends toward zero as interfacial tensions are reduced as low as $\sigma = 10^{-2}$ mN/m from $\sigma = 3$ mN/m. In addition, relative permeability curves for both water and oil phases become less curving or straighter with decreasing interfacial tensions.

4. For $\sigma > 3$ (σ_{c1}) mN/m, interfacial tensions show little impact on both residual oil saturation and relative permeability values for water and oil at $S_w = 50\%$.

5. For $\sigma > \sigma_{c1}$, two-phase flow and displacement can be handled as normal brine-oil flow. However, once $\sigma < \sigma_{c1}$, two-phase flow behaves very differently, and the effects of interfacial tensions must be considered in relative permeability models. As interfacial tension decreases to lower than the second critical point (i.e., $\sigma < \sigma_{c2}$), relative-permeability-curve shapes will continuously change, even though residual oil saturation and relative permeability values at $S_w = 50\%$ will hardly change.

6. Water-oil relative permeability is a function of fluid saturation (S_w), the logarithm of interfacial tension [$\log(\sigma_{wo})$], and the index of pore size distribution.

7. The experimental data and their analysis indicate that relative permeability for the low-interfacial-tension water-oil system is described by a function in the form:
$$k_r = S_w^{*\ A\log\sigma_{wo}+\lambda} .$$

There have been few studies in the literature regarding water-oil relative permeability behavior in multicomponent-mixture chemical flooding, with reported investigations mostly carried out using gas-oil systems. This work attempted to fill the gaps in studies of

water-oil systems under low interfacial tensions. We have found that it is not only more difficult to measure experimental results for a low-interfacial-tension water-oil system, but there also may exist more than one explanation for the observed flow phenomena. Thus, further studies are needed.

Acknowledgments

References

Abrams, A., 1975. The influence of fluid viscosity, interfacial tension, and flow velocity on residual oil saturation left by waterflood, SPE-5050, *Soc. Pet. Eng. J.,* October, 437–447.

Ahmed,T., 2001. Reservoir Engineering Handbook, Boston, Gulf Professional Pub., 2nd ed.

Asar, H.and Handy, L.L.,1988. Influence of interfacial tension on gas-oil relative permeability in a gas-condensate system, SPE-11740, Presented at the 1983 California Regional, Ventura, California, March 23-25, 1983, *SPERE*, February, 687-698.

Aziz, K. and Settari A. 1979, *Petroleum Reservoir Simulation*, Applied Science Publishers LTD, London.

Bardon C. and Longeron D.: 1980, Influence of very low interfacial tensions on relative permeability, *Soc. Pet. Eng. J.,* 391-401.

Brooks, R.H. and Corey, A.T., 1966. Properties of porous media affecting fluid flow, *J. Irrig. Drain. Div.*, 6, 61.

Brooks, R.H. and Corey, A.T., 1964. Hydraulic properties of porous media, Hydrology Papers, No. 3, Colorado State University, Ft. Collins, Colo.

Brooks, C.S. and Purcell, W.R., 1952. Surface area measurements on sedimentary rocks,

SPE222-G, Presented at the Fall Meeting of the Petroleum Branch, American Institute of Mining and Metallurgical Engineers, in Houston, October 1-3.

Chisholm, J.T., Kashikar, S.V., Knapp, R.M., Menzie, D.E., and Silfanus, N.J., 1990. Microbial enhanced oil recovery: Interfacial tension and gas-induced relative permeability effects, SPE-20481. This paper was prepared for presentation at the 65th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in New Orleans, LA, September 23-26, 16-176.

Coats, K. H.: 1987, Reservoir Simulation, Chapter 48, *Petroleum Engineering Handbook*, Society of Petroleum Engineers, Richardson, Texas, 48-1–48-20.

Conway, M.W., Smith, K., Thomas, T., and Schrau (!!! Missing first name here!!!), 1985, The effect of surface active agents on the relative permeability of brine and gas in porous media, SPE-28982, Presented at the SPE International Symposium on Oilfield Chemistry held in San Antonio, TX, February 14-17, 395-401.

Ekwere, J.P. and Khataniar, S., 1987. The effect of instability on relative permeability curves obtained by the dynamic-displacement method, SPE-14713, *SPE Formation Evaluation*, December, 469-474.

Fatt, I. and Dykstra, H., 1951. Relative permeability studies, *Trans.*, AIME, 192, 249–256.

Fulcher R.A., Ertekin T., and Stahl C.D., 1985, Effect of capillary number and its constituents on two-phase relative permeability curves, *J. Petrol. Technol.*, 249-260

Haniff, M.S. and Ali, J.K., 1990. Relative permeability and low tension fluid flow in gas condensate systems, SPE-20917, Presented at Europec 90, The Hague, Netherlands, 22-24, October, 351-358.

Harbert, L.W., 1983. Low interfacial tension relative permeability, SPE-12171, Presented at the 58th Annual Technical Conference and Exhibition held in San Francisco, CA, October 5-8.

Honarpour, M., Koederitz L. and Harvey A. H. 1986, *Relative permeability of petroleum reservoirs*, CRC Press, Inc., Boca Raton, Florida.

Huyakorn, P. S. and Pinder G. F., 1983, *Computational Methods in Subsurface Flow*, Academic Press, Inc., New York.

Istok, J.: 1989, *Groundwater Modeling by the Finite Element Method*, American Geophysical Union Water Resources Monograph 13.

Kumar, S. Torabzadeh, S.J., and Handy, L.L., 1985. Relative permeability functions for high- and low-tension systems at elevated temperatures, SPE-13670, Presented at the SPE 1985 California Regional Meeting, Bakersfield, California, March 27-29, 823-835.

Lawson, R.G. and Hirasaki, G.J., 1983. Analysis of the physical mechanisms in surfactant flooding, Paper (SPE-6003), Presented at the SPE-AIME 51st annual Fall Technical Conference and Exhibition, New Orleans, *Soc. Pet. Eng. J.,* 3–6.

Lu, G..X. et al., 2003. Investigation of effect of low interfacial tension on relative permeability, *Oilfield Chemistry J*., 20 (1), page numbers!!!

McDougall, S.R., Salino, P.A., and Sorbie, K.S., 1997. The effect of interfacial tension upon gas-oil relative permeability measurements: Interpretation using pore-scale models, SPE-38920, Presented at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, U.S.A., October 5-8.

Melrose, J.C. and Brandner, C.F., 1974. Role of capillary forces in dtermining microscopic displacement efficiency for oil recovery by waterflooding, *J. Cdn. Pet. Tech.* Oct.-Dec., 54–62.

Mulyadi, H., Mason, T., and Steer, D., 2002. Applying MAK gas-water relative permeability correlations to predict a gas-condensate relative permeability and production performance (case study), SPE-77935, Presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition held in Melboume, Australia, October 8-10.

Peaceman, D.W., 1977, *Fundamentals of Numerical Reservoir Simulation*, Developments in Petroleum Sciences, 6, Elsevier Scientific Publishing Company, Amsterdam-Oxford-New York.

Ronde, H., 1992. Relative permeability at low interfacial tensions, SPE-24877, Presented at the 67th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Washington, DC, October 4-7.

Talash, A.W., 1976. Experimental and calculated relative permeability data for systems containing tension additives, *Soc. Pet. Eng. J.,* 177–188.

Torabzadeh, S.J. and Handy, L.L., 1984. The effect of temperature and interfacial tension

on water/oil relative permeability of consolidated sands, SPE-12689, Presented at the SPE/DOE Fourth Symposium on Enhanced Oil Recovery held in Tulsa, OK, April 15-18.

Tang, G..Q. and Firoozabadi, A., 2002. Relative permeability modification in gas/liquid systems through wettability alteration to intermediate gas wetting, SPE8-1195, *SPE Reservoir Evaluation & Engineering*), December, 427-436.

Silpngarmlers, N., Guler, B., Ertekin, T., and Grader, A.S., 2002. Development and testing of two-phase relative permeability predictors using artificial neural networks, SPE-79547, *Soc. Pet. Eng. J.,* May, 299–308.

Talash A.W., 1976, Experimental and calculated relative permeability data for system containing tension additives, SPE-5810, SPE Improved Oil Recovery Symposium, Tulsa, *Soc. Pet. Eng. J.,* 177–188.

Wang, Y.D., Chen, Y.M, Jian, H., Zhou, Y.H., Zhou, B. (add all authors here!!!), 2002. A study of water-oil relative permeability under low interfacial tension, *J. of Jianghan Petroleum Institute,* 24 (3), 50-52.

Ye, Z.B., Peng, K.Z., Wu, X.L., and Huang, E.B., 2000. Laboratory study on the relative permeability curve during alkali-surfactant-polymer combination flooding in Karamay Oilfield, *ACTA Petroleum Sinica,* 21(1).49-54.
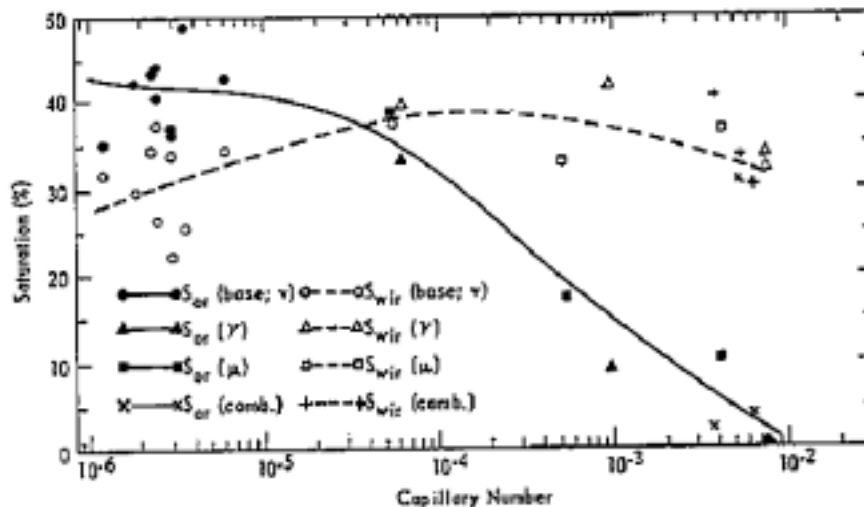
Figure 1.   Experimental residual saturations as functions of the capillary number (Fulcher et al., 1985)
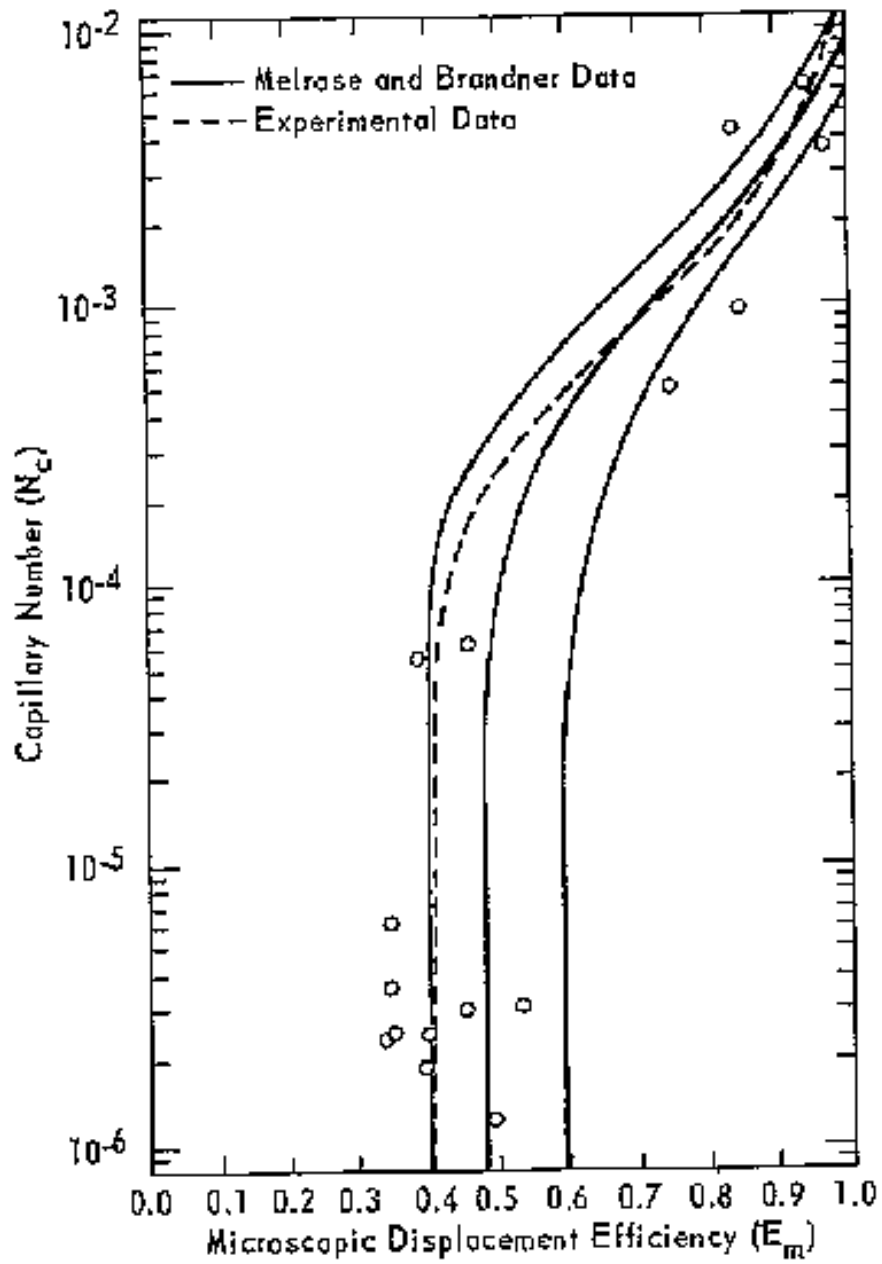
Figure 2.   Microscopic displacement efficiency as a function of capillary number (Melrose and Brandner, 1974)
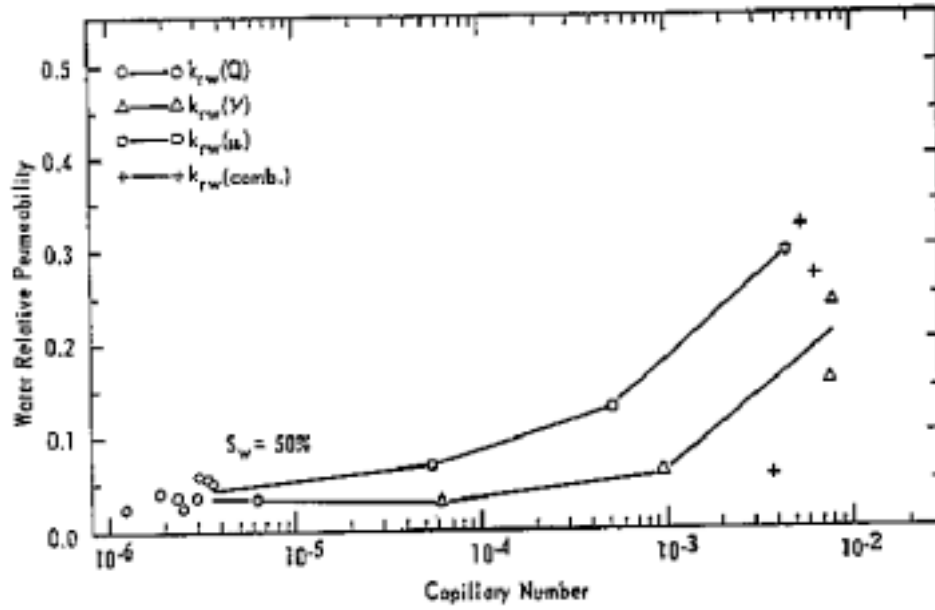
Figure 3.   Water relative permeabilities as functions of capillary number at 50%
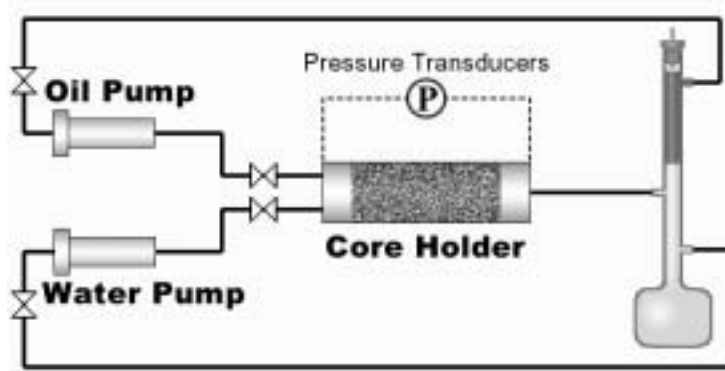   water saturation (Fulcher et al., 1985)

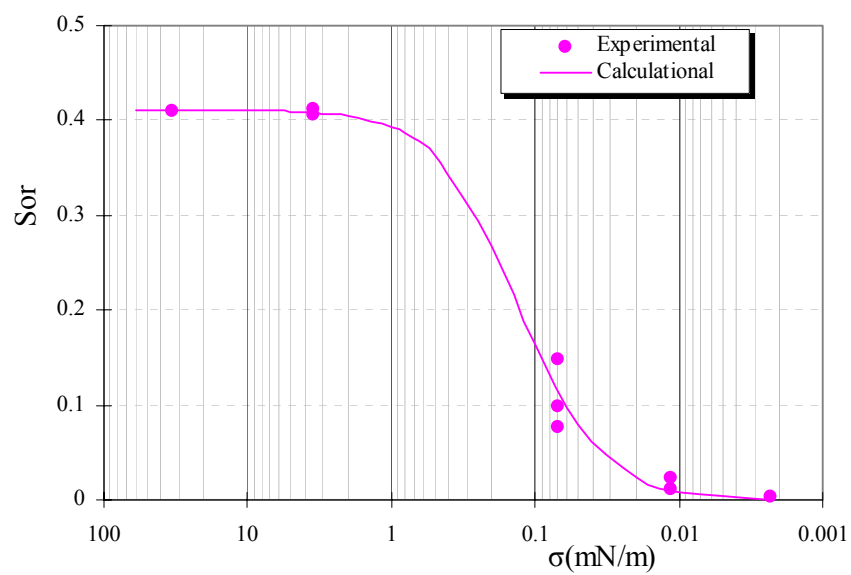Figure 4. Schematic diagram of the apparatus and experimental setup

Figure 5. Experimentally determined residual saturations as functions of the interfacial tensions
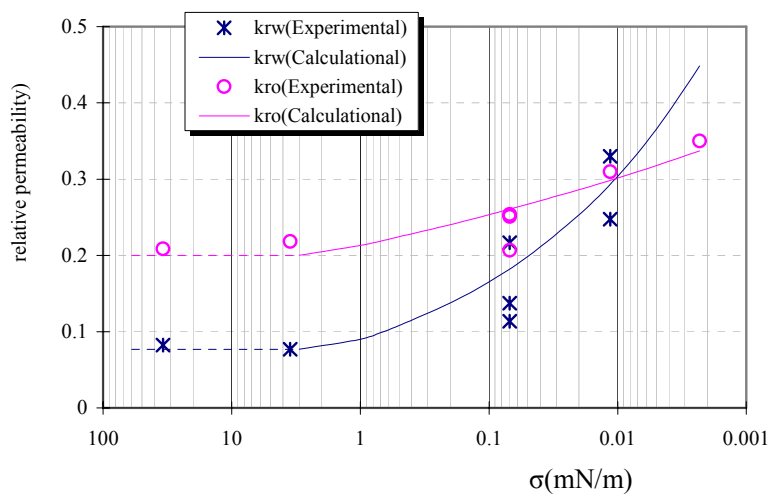
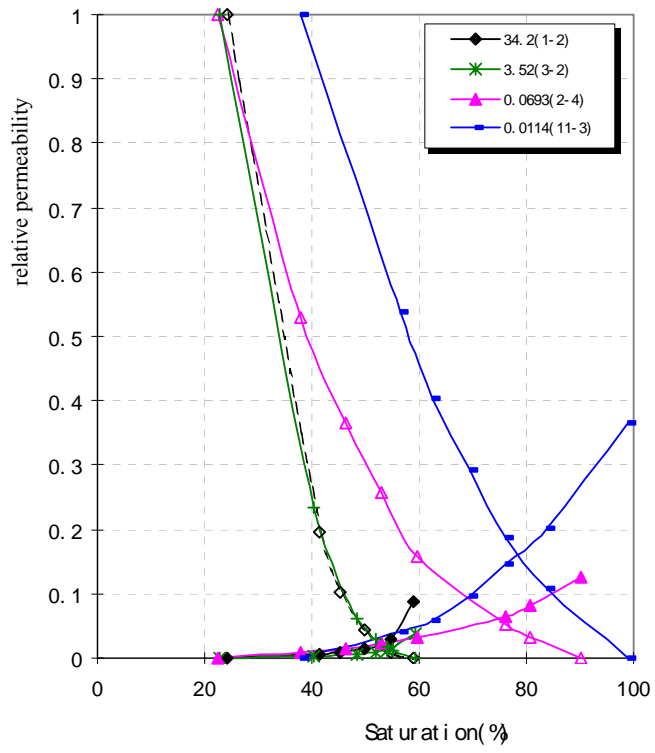Figure 6. Water-oil relative permeability as functions of the interfacial tension at 50% water saturation

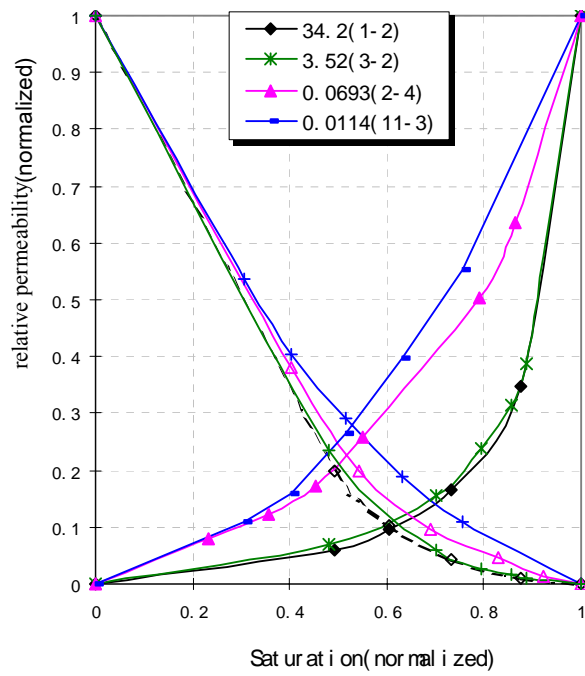Figure 7. Water-oil relative permeability curves for different interfacial tension values

Figure 8. Normalized water-oil relative permeability curves for different interfacial tension values
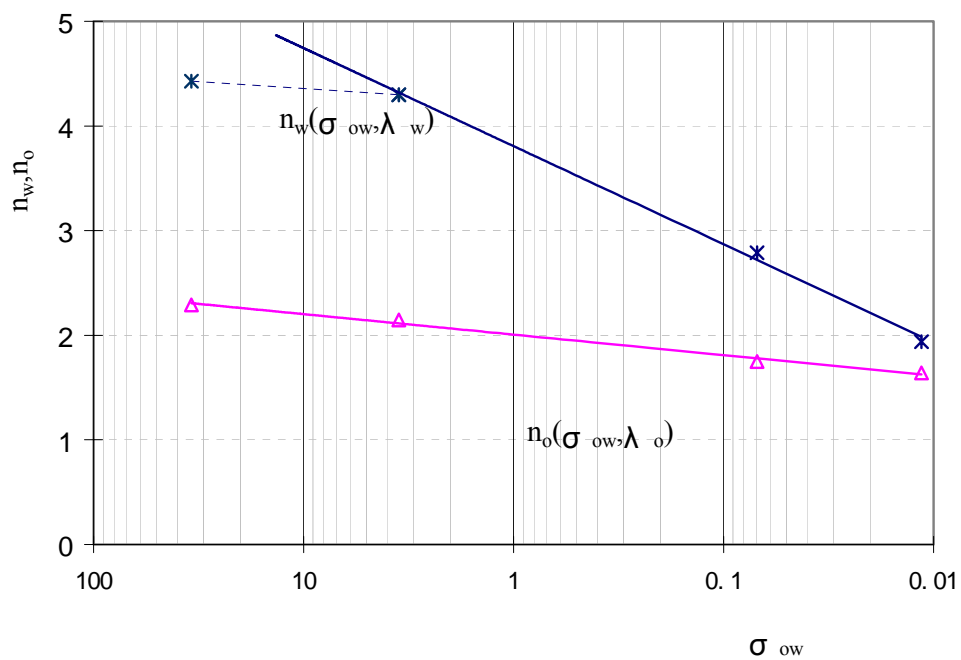
Figure 9. Correlations between interfacial tensions and exponential indexes, n_w and n_o

Table 1. Parameters of core samples used in experiments

Sample No.	Core Length (cm)	Effective Porosity	Permeability $(10^{-3}\mu \ m^2)$
1-2	6.530	0.135	228
1-1	6.522	0.140	237
1-4	6.554	0.135	228
1-3	6.487	0.135	256
3-2	6.521	0.135	276
2-1(fired)	6.558	0.131	273
2-3	6.453	0.134	263
2-4	6.474	0.133	281
11-4	5.030	0.179	252
3-1	6.426	0.142	333
3-3	6.541	0.135	246
11-2	4.987	0.191	168
11-3	5.048	0.195	255
3-4	6.517	0.134	226

Table 2. Flow rate and fluid parameters used in in experiments

Sample No.	Flow Rate (ml/min)	Aqueous Phase Viscosity (cp)	Interfacial Tension (mN/m)
1-2	0.1	1	34.2 (Basis water and oil system without surfactant)
1-1	1.0	1	
1-3	0.1	10	
1-4	1.0	10	
3-2	0.1	1	10^0
2-1(fired)	0.1	1	
2-3	0.1	1	10^{-1}
2-4	0.1	1	
11-4	0.1	1	
3-1	0.1	10	
3-3	0.1	1	10^{-2}
11-2	0.1	1	
11-3	0.1	1	
3-4	0.1	1	10^{-3}

Table 3. Exponential indexes of relative permeability functions, calibrated using the experimental data

σ (mN/m)	n_w	n_o	Sample Number
Basis water-oil system	4.428	2.289	4
10^0	4.298	2.148	2
10^{-1}	2.788	1.749	4
10^{-2}	1.940	1.639	3